EXELON GENERATION COMPANY, LLC' S COMMENTS ON THE ILLINOIS POWER AGENCY'S <u>DRAFT ZERO EMISSION STANDARD PROCUREMENT PLAN</u>

Pursuant to 20 ILCS 3855/1-75(d-5)(C), Exelon Generation Company, LLC ("Exelon") submits these comments to the Illinois Power Agency ("IPA") regarding the July 11, 2017 draft Zero Emission Standard Procurement Plan (the "Draft ZES Plan"). Exelon, individually or through its subsidiaries, has participated in the competitive procurement processes under which contracts for the electricity needs of Ameren and ComEd have been awarded since the end of the transition period at the end of 2006. Based upon its experiences in procurement events in Illinois and elsewhere, and its experience as the owner of numerous merchant nuclear facilities, Exelon has several recommendations to improve the Draft ZES Plan's fidelity to the statutory language and purpose.

I. INTRODUCTION

Exelon commends the IPA for its careful and thoughtful approach in constructing the Draft ZES Plan. Exelon's comments focus largely on the bid scoring process. In particular, Exelon recommends several changes to the bid scoring formula to improve its accuracy in selecting the zero emissions facilities the Legislature intended to target: those that will "minimiz[e] carbon dioxide emissions that result from electricity consumed in Illinois," "minimiz[e] sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect [Illinois] citizens," and provide the greatest "incremental environmental benefits," including in particular "any existing environmental benefits that are preserved by the procurements … and would cease to exist" otherwise.[1] Exelon also recommends a number of clarifications of the Draft ZES Plan. We have included with our submission a redlined version of the Draft ZES Plan to illustrate our suggested

[1] *See* 20 ILCS 3855/1-75(d-5)(1)(C).

revisions. We have also included a revised version of certain worksheets from the IPA's Appendix E to demonstrate how our suggestions would be implemented.

A. Summary of Recommended Changes to Bid Scoring Process.

1) The Draft ZES Plan proposes selecting facilities based in part on the Facility Size Metric, which provides an advantage to large facilities. The IPA should eliminate that variable from its selection formula. Consistent with the Act's directives, the IPA should be seeking to select the combination of facilities that provides the greatest "incremental environmental benefits." That means that a facility should be selected based on the environmental benefits it can provide on a per-ZEC basis. If two smaller facilities can together produce more environmental benefits than a single larger facility for the same number of ZECs, then (all else equal) the IPA should select the smaller facilities. For example, if the IPA's procurement budget would allow it to either select two 500-MW plants that would together displace 1,000 tons of pollutants, or a single 1,000-MW plant that would displace 900 tons of pollutants, then (all else equal) the IPA should clearly select the two 500-MW plants. But the Facility Size Metric bonus given to the larger plant because of its larger size would (all else equal) give it a higher overall score than either of the two smaller plants. That perverse outcome would be contrary to the statute's goals and selection criteria.

2) Exelon recommends three changes to the Draft ZES Plan's evaluation of a facility's economic stress. First, Exelon recommends that the IPA cap the Economic Stress Multiplier. Once a certain level of economic distress is reached, all facilities beyond that level have a similarly high likelihood of retirement. The degree to which the facility's costs *exceed* that level do not increase the probability of its retirement on a linear basis. And if two different facilities both face a similar probability of retirement, any difference in their costs should be irrelevant. Exelon therefore suggests that the IPA set a cap on the Economic Stress Multiplier. Since the maximum ZEC price

is \$16.50/MWh, a generic unit that received the \$31.40/MWh baseline would be in maximum economic distress if its costs exceeded \$16.50/MWh above the \$31.40/MWh baseline. Accordingly, the maximum Economic Stress Multiplier for that baseline unit should be 1.53 (equal to (\$16.50 + \$31.40) / \$31.40), and the IPA should adopt a cap of 1.53 for all facilities' Economic Stress Multipliers.

Second, economic stress is a function of costs in relation to revenues, and a facility's revenues may differ substantially from the generic \$31.40/MWh baseline proposed by the IPA. Facilities may receive higher or lower revenues because their nodal price differs from the Northern Illinois Hub ("NI Hub") price used for the \$31.40/MWh baseline. This difference is known as "basis." Facility-specific basis is publicly available information. A nuclear facility's nodal price can vary substantially from the NI Hub price—for some units nearly \$9/MWh above or below the NI Hub price. Negative basis can be a significant contributor to a nuclear facility's economic distress, and the IPA should account for it. Exelon proposes that the IPA should assess each facility's economic stress by the ratio of its costs to the \$31.40/MWh baseline *adjusted* for the facility's basis, while (consistent with our suggestion above) still capping the Economic Stress Multiplier at 1.53.

Third, if the IPA adopts our suggestion to account for basis, it can also eliminate the Risk-Based Multiplier, which discounts by half the risk of retirement faced by a rate-based facility. That can be fully addressed by the Economic Stress Multiplier, if a rate-based facility is assumed to have revenues equal to its costs—that is, to have an Economic Stress Multiplier of 1.

3) The Draft ZES Plan assumes that a retiring nuclear plant will be replaced entirely by generation within the same state. It is assuredly reasonable for the IPA to adopt simplifying assumptions to ensure that the procurement is administrable and transparent. In this instance,

however, the IPA can do so while still recognizing that, due to the interconnected nature of the electric grid, a retiring nuclear plant will be replaced partly by generation located within the same state and partly by generation located elsewhere. Based on data included in the Report prepared pursuant to H.R. 1146, which studied the emissions impacts that would result from the closure of nuclear plants in Illinois, approximately 33% of the replacement generation would be in Illinois. Exelon suggests that the IPA accordingly assume that the state in which the retiring facility is located will account for 33% of replacement generation, and that the remaining replacement generation is allocated in equal shares to each other state in the facility's RTO. This approach, Exelon submits, would appropriately balance the various factors that the IPA must weigh in structuring its procurement, including accuracy, transparency, and administrability.

4) In determining a facility's carbon dioxide score, the Draft ZES Plan uses certain capacity-import metrics as a proxy for the fraction of power consumed in Illinois that is imported from other states. However, capacity transfer limits do not necessarily reflect actual energy flows. Exelon suggests that the IPA instead assess whether the state in which a zero emissions facility is located is a net importer or exporter of electricity—that is, whether its generation exceeds its electricity consumption (or "load"). For example, in 2016, Illinois produced more electricity than it consumed, and Illinois load amounted to approximately 82% of Illinois generation, net of transmission and distribution losses. It thus reasonable to conclude that 82% of the zero emissions electricity generated by an Illinois zero emissions facility is consumed in Illinois, abating carbon that otherwise would be consumed in the facility's absence, and to assume that the remaining 18% of the zero emissions electricity is exported and consumed elsewhere. The IPA should devise similar metrics for other states. For facilities in net-exporting states, the percentage of the state's generation in excess of its load could be assumed to be consumed in Illinois. This is an extremely

conservative assumption, because in reality the electricity exported from a state is consumed throughout the entire RTO, not in Illinois alone. For facilities in net-importing states, it would be reasonable to conclude that *none* of the energy generated by that facility is consumed in Illinois, because generation in that state is presumably consumed locally to satisfy demand. But again to be conservative, the IPA could assume that 10% of the electricity from such units is consumed in Illinois.

B. Summary of Other Recommendations and Requested Clarifications.

In addition to the recommended revisions to the bid scoring methodology described above, Exelon has several other recommendations for, and requested clarifications of, the Draft ZES Plan.

1) The Draft ZES Plan raises the issue of how the IPA will handle a circumstance in which top-ranked facilities together will deliver less than the 16% statutory target, but the next-ranked facility would have the capability to deliver significantly more than the 16% statutory target. As an initial matter, the statutory language gives IPA sufficient discretion to procure zero emission facilities in a way that will minimize the risk of this problem. The statute says that ZECs should be procured in an "amount *approximately* equal to 16% of the actual amount of electricity delivered by each electric utility to retail customers in the State during calendar year 2014" (emphasis added). The term "approximately" gives the IPA flexibility; the statute does not require IPA to procure *exactly* 16% of electricity delivered to retail customers. So the IPA has statutory discretion to stop selecting plants if, for example, it reaches 15% of electricity delivered to retail customers, or to select a final plant even if that plant's expected generation would result in the procurement of 17% of electricity delivered to retail customers. In neither case would the IPA need to select a "marginal" facility that will not receive ZECs for all of its generation. If the IPA determines that it must select a "marginal" facility, Exelon understands the IPA to propose that the

marginal facility would be compensated only for the quantity of ZECs needed to reach the 16% target. The remaining ZECs produced by a marginal facility would be procured but treated as unpaid contractual volumes. To the extent that is the IPA's proposal, Exelon asks that the IPA clarify and confirm as much.

2) The Draft ZES Plan seeks comment on how unpaid contractual volumes should be priced if they can subsequently be paid. Exelon recommends that unpaid contractual volume should be compensated at the price prevailing in the year that the unpaid volume was incurred. This is consistent with the statutory language, which refers to the unpaid contractual volumes as volumes for a particular delivery year: "Unpaid contractual volume *for any delivery year* shall be paid in any subsequent delivery year in which such payments can be made without exceeding the amount specified in this paragraph (2)." Accordingly, the per-ZEC price for that unpaid contractual volume should be the per-ZEC price that prevailed in that delivery year.

3) In determining the emissions factors for CO_2, PM, NO_x, and SO_2 of replacement generation, the Draft ZES Plan report describes the calculation of a coal and gas blended rate,[2] but the Appendix E spreadsheet instead calculates a state's *average* emissions rate. But as the Draft ZES Plan recognizes, a state's average emissions rate incorporates the emissions of zero emissions resources—such as nuclear resources and renewable resources—that are at the bottom of the supply stack. These resources will not form part of the *marginal* generation mix that will replace the output of a retiring nuclear plant. Because coal and gas plants are assumed by the IPA to be the marginal units called upon to replace a retiring nuclear plant, the IPA should use a statewide emissions rate resulting from the weighted average of coal and gas generation within a state.

[2] *See* Draft ZES Plan at 34.

4) Finally, Exelon has several technical recommendations that are discussed in detail below. Exelon has also identified a few errors in the Excel spreadsheet formula included as Appendix E to the Draft ZES Plan; those errors are also outlined below.

II. DETAILED EXPLANATION OF RECOMMENDED CHANGES TO BID SCORING PROCESS.

A. The IPA Should Eliminate The Facility Size Metric.

The Draft ZES Plan currently calls for each bid's score to be multiplied by a "Facility Size Metric," which is designed to "account for the size of zero mission facility relative to the average size of a nuclear facility sited in that RTO."[3] This factor should be eliminated from the scoring formula. A facility's size bears no relation at all to the environmental benefit resulting from each ZEC it produces, and giving weight to a facility's size could result in perverse consequences that are contrary to the statutory purpose.

The ZES statute itself confers no advantage on larger facilities—all facilities are to be judged based on the same statutory environmental public interest criteria. Likewise, the statute's structure and purpose do not support advantaging larger facilities. The ZES statute does not limit the number of facilities that may receive ZECs. And because the number of ZECs that a nuclear facility will receive each year is directly tied to its actual generation that year,[4] multiple smaller facilities that combine to generate the same number of MWhs as a larger facility will produce the same number of zero-emission MWhs of electricity, and will receive the same number of ZECs (between them) as the larger facility. It is therefore irrelevant whether zero-emission electricity comes from one large facility or two smaller facilities, if Illinois is receiving the same number of zero-emission MWhs of electricity and paying for the same number of ZECs. There is no reason

[3] *Id.* at 44.
[4] *See* 20 ILCS 3855/1-75(d-5)(1).

to prefer a single large facility over multiple smaller facilities that deliver the same environmental benefits for the same number of ZECs and thus the same cost.

Moreover, if a larger facility is preferred as a result of the Facility Size Metric, that facility may be selected to receive ZECs over smaller facilities even if the those smaller facilities, in total, would deliver *more* net environmental benefits to Illinois. The scoring bonus to the larger facility from the Facility Size Metric might outweigh the scoring bonus to the smaller facilities from delivering more environmental benefits to Illinois. Thus, the end result may simply be fewer environmental benefits for Illinois—a result that is directly contrary to the statutory public interest criteria that the IPA is required to consider. This is not an unlikely result. Given the wide variation in nuclear unit sizes, the Facility Size Metric is likely to substantially alter the outcome of the selection process, even though facility size is irrelevant to the environmental benefits that will be conferred on Illinois. Exelon recommends that the IPA eliminate the Facility Size Metric.[5]

To be clear, Exelon certainly agrees that a facility's size should be considered in determining how *many* facilities to select to receive ZECs. The Zero Emission Standard requires the IPA to procure contracts with "zero emission facilities that are reasonably capable of generating [ZECs] in an amount approximately equal to 16%" of the electricity consumed in Illinois.[6] However, for the reasons given above, a facility's size should not be a component of the facility's

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[5] To the extent the IPA chooses to retain the Facility Size Metric (which it should not), Exelon recommends that the metric reflect a facility's actual total size, rather than the fraction of the facility owned by a bidding party. Thus, for example, if a bidding party owns 50% of a 1,000 MW facility, the facility size metric would be based on a size of 1,000 MW, not 500 MW. Because retirement decisions are made on a facility-by-facility basis, the facility as a whole—not just the share owned by the bidding party—will be preserved by the program. Accordingly, Illinois will receive the environmental benefits of the entire facility should it select that facility to receive ZECs. Thus, reflecting only that portion of a facility owned by the bidding party would arbitrarily disadvantage all facilities that are jointly owned, even though those facilities may produce greater incremental environmental benefits for Illinois if they are selected.

[6] *See* 20 ILCS 3855/1-75(d-5)(1).

score; it should only become relevant once a facility has been selected, to determine whether other facilities need to be selected to meet the state's 16% ZEC goal.

B. The IPA Should Cap the Economic Stress Multiplier and Assess Economic Stress By Comparing Costs With Revenues.

Exelon agrees that facility bid scores should reflect the economic stress that a facility is facing. The ZES requires that the IPA take into account the "incremental environmental benefits resulting from the procurement, such as any existing environmental benefits that are preserved by the procurements … and would cease to exist if the procurements were not held, including the preservation of zero emission facilities."[7] A facility's economic distress is relevant to whether, absent selection, it would "cease to exist" and thus whether selection would "preserve[]" it.[8] Likewise, Exelon agrees with the IPA's assessment that, all else equal, "zero emission facilities with higher operating costs … are more likely to face economic stress and potential closure than facilities with lower operating costs."[9]

However, Exelon recommends three changes to the IPA's proposed Economic Stress Multiplier. The second and third of these suggested changes are interrelated.

1. Cap on the Economic Stress Multiplier. First, under the statute, the IPA is assessing whether a facility is likely to retire absent ZEC revenues—that is, whether selection of that facility to receive ZECs would "preserve" that facility's environmental benefits from the risk of retirement. But if a facility's costs outstrip its revenues by a sufficiently large margin, the closure risk will not track costs on a linear basis. Thus, all facilities that exceed a certain cost to revenue ratio can be expected to have a similar level of retirement risk. For example, a merchant facility with costs of $100/MWh and a merchant facility with costs of $150/MWh are both essentially

[7] *See id.* 1-75(1)(C).
[8] *Id.*
[9] *See* Draft ZES Plan 42-43.

guaranteed to retire because of their astronomical costs. But under the IPA's metric, the latter facility's score would be significantly higher than that of the first facility, even though both facilities are equally likely to retire, and thus are equally stressed in the only way relevant to the IPA's consideration. Indeed, under IPA's proposed scoring methodology, the latter facility's greater Economic Stress Multiplier would likely overwhelm any differences in those facilities' environmental benefits to Illinois.

Exelon therefore recommends implementing a cap on the Economic Stress Multiplier to reflect the fact that, beyond a certain threshold, a facility is sufficiently stressed that it is as likely to retire as any other facility beyond the threshold. Because the statutory maximum ZEC Price is \$16.50/MWh, any facility applying for ZECs is committing to operate for an incremental \$16.50/MWh, recognizing that distress beyond that amount will not be addressed by the ZES program. Thus, assuming a baseline revenue level of \$31.40/MWh, any facility with costs greater than \$47.90/MWh (\$31.40/MWh + \$16.50/MWh) should be assumed to be under maximum economic stress. This approach would lead to a maximum Economic Stress Multiplier of 1.53 (\$47.90 divided by \$31.40).

Applying a cap to the Economic Stress Multiplier would also make the procurement process more administrable. It will reduce the incentive bidders may have to inflate their costs in an effort to gain an edge in the procurement process, and will reduce the need for the IPA to question whether (for example) large-dollar future capital expenditures included in a bidder's costs are really necessary and likely to be made.

2. Account for Basis Differential Between Nodal Energy Prices and NI Hub Energy Prices. Facility costs are only half of the equation when it comes to economic distress. A facility can withstand high costs if it is receiving sufficient revenues through state-approved cost-based rate recovery or from its retail, bilateral wholesale, or wholesale auction sales. Therefore, a facility's revenues are also important in determining whether it faces economic distress. The Draft ZES Plan, however, does not account for the revenue side. Instead, it assumes that every facility's revenues are the same, by comparing a facility's costs to a Base Market Price Index of $31.40/MWh based in part on futures prices at the NI Hub. But the actual revenue received by plants will vary significantly depending on, for example, local transmission constraints that can create a large price differential between a plant's locational marginal price and the NI Hub price. That differential is known as "basis."

In PJM in 2015-16 (the same year as the data used to calculate the Base Market Price Index), facilities' basis ranged from approximately $-8.93/MWh (meaning that the average price at that facility's node was about $8.93/MWh *less* than the NI Hub price) to approximately $7.81/MWh (meaning that the price at that facility's node was about $7.81/MWh *greater* than the NI Hub price). It would make little sense to compare the economic stress faced by two facilities without taking into account the possibility that their average nodal energy prices may differ by more than $16/MWh. But the Draft ZES Plan would not reflect any difference between those facilities.

Exelon therefore believes that the Draft ZES Plan's "comparison of operating costs to a statutorily referenced baseline market price index" is not "appropriate for establishing an economic stress multiplier."[10] The purpose of evaluating economic stress is to ascertain the likelihood that, without ZECs, a facility's zero emission attributes would not be preserved. But no business owner, when evaluating whether to retire a unit, would focus solely on its costs without regard to its revenues. A prudent business owner would evaluate costs in relation to revenues.

[10] *See id.* at 43.

Accordingly, to measure the level of economic distress a facility actually faces, and thus the potential for its retirement, Exelon suggests that the IPA adjust the $31.40/MWh baseline by the basis between the NI Hub price and the nodal price for that facility during 2015-16. Although this heuristic does not perfectly capture unit-specific revenues—which can depend on contractual prices, the quantity of energy sold into the market, capacity revenues, and other factors—it does provide a rough estimate of the differences between bidding units' potential revenues. Information regarding basis is publicly available, and we have included it in Appendix A to these comments for the IPA's convenience.[11]

Consistent with our recommendation for a cap set forth above, IPA should still cap the Economic Stress Multiplier at 1.53 even if it also accepts our recommendation to adjust the BMPI for basis.

3. Treatment of Rate-Based Facilities. If the IPA adopts our proposal to consider revenues in relation to costs, it can also eliminate the Risk-Based Multiplier. The IPA proposed to apply a multiplier of 0.5 to the bid scores of facilities with rate-based cost recovery, and asked whether "this multiplier level is appropriate."[12] Exelon fully agrees with the IPA that "merchant facilities have a greater risk of early retirement brought about by economic stress than facilities with rate-based cost recovery," and that the vast majority of nuclear facilities that have retired prematurely in recent years are merchant facilities operating in competitive markets.[13] Exelon also agrees with the IPA's interpretation of the ZES: the statute does not prohibit rate-based facilities from applying for ZECs, but does direct the IPA to take into account the incremental environmental benefits that

[11] For PJM, basis data for 2015-2016 can be found at http://www.pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx. For MISO, basis data for 2015-2016 can be found at https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx. Select "Browse All Available Reports," and then select "Historical LMP Historical Annual Day-Ahead LMPs (zip)".
[12] *See* Draft ZES Plan 43.
[13] *See id.* at 41.

will be preserved through selection of the facility.[14] If the rate-based facility is likely to continue operating irrespective of its receipt of ZECs, then it is appropriate for the IPA to take that into account in determining the facility's score.

But if the IPA is considering costs as well as revenues as part of its Economic Stress Multiplier, a separate Risk-Based Multiplier is unnecessary. Rather than apply a separate 0.5 multiplier to rate-based facilities, the IPA could instead simply assume that a rate-based facility's revenues are equal to its costs, so that a rate-based facility's Economic Stress Multiplier is equal to 1. Exelon believes that such an approach would be a more reasonable way to reflect the reality that rate-based units are guaranteed cost-based recovery and therefore less susceptible to economic distress than non-regulated units.

C. The IPA Should Revise Its Assumption That Replacement Generation For A Retiring Facility Will Come Solely From The State In Which That Facility Is Located.

The Draft ZES Plan states that, for purposes of its bid evaluation and selection process, the IPA will assume that the "replacement generation mix" that would replace a bidding zero emission facility will be located within "the state in which the zero emission facility is located."[15] That assumption affects the calculation of the "Emission Scoring Metric" and the "Emissions Scoring Weight" for SO_2, NO_x, PM_{10}, and $PM_{2.5}$ analyzed by the IPA.

Exelon appreciates the difficulty of attempting to determine the precise generation mix (and its location) that would replace a zero emission facility if that facility retired. Because of the complexity of the interconnected electrical grid, and the uncertainty regarding how the resource

[14] *See id.* at 42.

[15] Draft ZES Plan 32. The IPA also assumes that the replacement generation mix will be comprised entirely of coal- and natural gas-fired resources, given that those resources are typically the marginal resources in the generation supply stack, and so would be the first resources to be dispatched in the event of the retirement of a zero emission facility. Exelon agrees that the marginal generation mix is likely to be overwhelmingly comprised of fossil-fuel resources, and thus supports the IPA's approach.

mix and transmission network will change over time, it is impossible to predict with certainty which resources would replace the energy and capacity that would be lost if a nuclear facility retired.

Accordingly, Exelon agrees that the IPA reasonably can make certain simplifying assumptions regarding the likely generation mix that would replace a zero emission facility. In particular, because emissions data is publicly available at the state level, it is reasonable for IPA to assign a portion of the replacement generation mix to a particular state as a whole, rather than attempting to designate particular resources within that state as replacement resources and then investigate the emissions profile of *each* such resource. Because of data availability, it is also appropriate for IPA to use state-based emissions data rather than estimating the emission profile of particular zones.

However, instead of assuming that all replacement generation will come solely from within the state, the IPA can adopt a simplifying assumption that more closely tracks the available data. In connection with the HR 1146 report, PJM modeled the likely emissions impact in 2019 resulting from the retirement of nuclear facilities in Illinois. PJM concluded in that, in the event that Byron 1 and 2 and Quad Cities 1 and 2 retired, 32.1% of the RTO-wide increases in CO_2, 30.2% of the RTO-wide increases in SO_2, and 36.9% of the RTO-wide increases in NO_x resulting from replacement generation would occur in Illinois.[16] While these findings concern emissions rather than generation, emissions are obviously highly correlated to generation. These findings suggest that, if an Illinois nuclear plant retired, approximately 33% of the replacement generation would be located in Illinois, and the remainder would be elsewhere in the RTO.

[16] *See* PJM Interconnection, LLC, PJM Response to Illinois Commerce Commission Request to Analyze the Impact of Various Illinois Nuclear Power Plant Retirements 9 (Oct. 21, 2014), Appendix to HR 1146 Report, available at http://www.pjm.com/-/media/committees-groups/committees/teac/20150107/20150107-pjm-response-to-icc-request-to-analyze-the-impact-of-nuclear-retirements.ashx?la=en.

Exelon recommends that IPA rely on this data to estimate that 33% of replacement generation will be located within the state of a retiring nuclear plant, and the remaining replacement generation will come from the remainder of the RTO, allocated in equal shares to the other states in the RTO. For example, the Emission Score for SO_2 for a zero emissions facility in Pennsylvania would be calculated by summing the weighted emission scores for each of the states in PJM, each of which would be assumed to have a portion of the replacement generation mix, as follows:

State	Replacement Generation Share		SO_2 Emission Factor[17]		SO_2 Emissions Scoring Weight[18]	**TOTAL**
PA	33.0%	*	1.411	*	5.0%	0.023
IL	7.4%	*	1.044	*	100.0%	0.077
MD	7.4%	*	0.813	*	5.1%	0.003
MI	7.4%	*	1.675	*	8.2%	0.010
NJ	7.4%	*	0.046	*	2.9%	0.000098
OH	7.4%	*	1.895	*	8.3%	0.012
VA	7.4%	*	0.487	*	6.3%	0.002
DE	7.4%	*	0.079	*	To be calculated	To be calculated
KY	7.4%	*	1.691	*	To be calculated	To be calculated
WV	7.4%	*	0.858	*	To be calculated	To be calculated
					SUM	To be calculated

[17] These figures would correspond to the "SO2 Ratio (bb)" column of the "2_Emissions Factors" worksheet of Appendix E, but have been corrected to reflect the average emissions of *only* the coal and natural gas generation within each state, a correction that is explained in greater detail in Section III.C.
[18] These figures are from page 1 of Appendix C of the Draft ZES Plan.

That summed total would then be multiplied by the pollutant's maximum score (in the case of SO_2, 25). This approach, Exelon submits, would appropriately balance the various factors that the IPA must weigh in structuring its procurement, including accuracy, transparency, and administrability.

D. The IPA Should Use A Different Proxy For Estimating Illinois Carbon Consumption For Purposes Of CO_2 Scoring.

As the IPA correctly recognizes, because of the interconnected nature of the grid and the lack of public data on electricity flows from other states into Illinois, it is challenging to discern where electricity consumed in Illinois originated. But the IPA is required by statute to assess a bidding nuclear facility's contribution to reducing carbon consumed in Illinois. To do so, the IPA proposes to use a proxy for the ratio of power flowing into Illinois from other states to estimate how much power from a nuclear facility is consumed within Illinois.

Exelon agrees with the thrust of the IPA's approach. Although it is difficult to know with certainty where electricity consumed in Illinois is generated, or precisely how the carbon intensity of electricity consumed in Illinois would change in the event a particular nuclear plant retires, the IPA reasonably can use proxies for power flows into and out of Illinois to provide an estimate. However, Exelon proposes a different proxy than the one set forth in the Draft ZES Plan.

Exelon suggests that the IPA frame the carbon consumption analysis around this question: what portion of a zero emission facility's energy is likely currently being consumed in Illinois, and thereby abating carbon consumption by Illinois consumers that would take place in the plant's absence? A reasonable and conservative answer to that question would begin by considering whether the state in which the zero emissions facility is located is a net importer or exporter of electricity—that is, whether its generation exceeds its electricity consumption (or "load"). In 2016, the last year for which comprehensive EIA data are available, Illinois produced more electricity than it consumed, and Illinois load amounted to approximately 82% of Illinois generation, net of transmission and distribution losses.[19] It thus reasonable to conclude that 82% of the zero emissions electricity generated by an Illinois zero emissions facility is consumed in Illinois, abating carbon that otherwise would be consumed in the facility's absence, and the remainder is exported to other states.

For plants located in other states that are net exporters of electricity, IPA should identify the percentage of the state's generation in excess of the state's load (the state's "export factor"). A state's export factor can serve as a conservative proxy for the share of the zero emissions facility's output that is consumed in Illinois.[20] In calculating the export factor, the state's generation totals should be adjusted for transmission and distribution losses. This adjustment is necessary for accuracy. Because electricity dissipates when traveling any distance, even a state that had no imports or exports of electricity would be expected to have greater generation than load; the difference between the two represents the electricity lost during transmission and distribution between generation and consumption. Accordingly, each state's generation figures must be adjusted to account for this reality. In 2016, in the United States as a whole, generation exceeded consumption by approximately 10%, which provides a rough proxy for average national transmission and distribution losses. Each state's generation total should be reduced by the same percentage—approximately 10%—to account for the fact that that amount of generation is lost and not consumed. Accounting for that change, we have included each state's export factor, drawn from 2016 EIA data on state-by-state consumption and generation, in Appendix B to these comments.[21]

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[19] EIA Electric Power Monthly, February 2017, which can be accessed here: https://www.eia.gov/electricity/monthly/.

[20] The proxy is conservative because it significantly overstates the likely contribution made by an out-of-state facility to the abatement of Illinois carbon consumption, since that facility's electricity is exported to the entire RTO, not only to Illinois.

[21] The data can be found in Tables 1.3.B and 5.4.B of the February 2017 "Electric Power Monthly" produced by the EIA, which can be accessed here: https://www.eia.gov/electricity/monthly/. Select "February 2017" from "Previous Issues" to obtain the year-to-date figures for 2016 through December 2016.

For zero emissions facilities located in states that are net importers of electricity, it would be reasonable to conclude that such zero emissions facilities provide no Illinois carbon consumption benefit. Nevertheless, in recognition that there may be times during the year that these states are net exporters, the IPA could assume that no less than 10 percent of any zero emission facility's output is consumed in Illinois. Again, this is a conservative estimate that likely significantly overstates the contribution of such zero emissions facilities in abating Illinois carbon consumption.

The IPA need not analyze state CO_2 emission rates. The statute's focus with respect to carbon is on minimizing the carbon consumption of Illinois residents, not on minimizing carbon produced by replacement generation. Replacement generation will not necessarily be consumed in Illinois. It is more consistent with the statutory language to assess the degree to which a zero emission facility's electricity is consumed in Illinois, thereby abating carbon emissions.

Alternatively, to the extent that the IPA elects not to adopt the generation/load ratio approach described above, Exelon believes that the IPA should select proxies for carbon consumption that are consistent between MISO and PJM and are not likely to underestimate the power flows into Illinois from other states. Accordingly, if the IPA does not adopt the above-described approach, Exelon supports the IPA's proposed approach for calculating the power flow into the Ameren zone, which assesses the percentage of the zone's reliability requirement that is satisfied by capacity located within the zone. Applying that methodology, the IPA estimated that 7.8% of electricity generated in MISO outside Zone 4 is likely to be consumed in Zone 4. Exelon recommends that a metric consistent with the approach taken in MISO should be applied in PJM.[22]

[22] The IPA's approach to calculating flows of power into PJM proposes to use the Capacity Emergency Transfer Objective ("CETO"), which is the *minimum* amount of out-of-zone capacity that can be relied upon to meet the zonal reliability requirement during emergency conditions.

Although (as the IPA notes) PJM does not publish the actual capacity that a locational deliverability area ("LDA") imports from other LDAs in PJM, the IPA could obtain that figure by subtracting the capacity that cleared in PJM's ComEd LDA in the 2017-18 capacity auction—22,551 MW[23]—from the total zonal reliability requirement for PJM—28,991 MW.[24] The remaining 6,440 MW of capacity needed to satisfy the reliability requirement (or about 22.2%) came from outside the ComEd zone. Thus, if the IPA declines to adopt the generation/load ratio approach described above, then in accordance with its approach in MISO, the IPA could assume that 22.2% (rather than 7.9%) of the power generated in PJM outside the ComEd LDA is likely to be consumed in the ComEd LDA.[25]

III. OTHER RECOMMENDATIONS AND REQUESTED CLARIFICATIONS.

A. The IPA Has Discretion to Procure *Approximately* 16% of Electricity Delivered to Retail Customers, to Avoid a Partial Procurement from a Marginal Facility.

In the Draft ZES Plan, the IPA considers how it will address a situation in which the top-ranked facilities together will deliver less than the 16% statutory target, but the next-ranked facility would result in significantly more than the 16% statutory target. The statutory language gives the IPA discretion to procure zero emission facilities so as to minimize the risk that this problem arises.

[23] PJM Interconnection, LLC, 2017/2018 Delivery Year Summary of Auction Results, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-results.ashx?la=en.

[24] PJM Interconnection, LLC, 2017-2018 RPM Base Residual Auction Planning Parameters (June 2, 2014), http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx?la=en.

[25] Alternatively, to the extent the IPA continues to rely upon capacity emergency transfer metrics for PJM, it should use PJM's Capacity Emergency Transfer Limit ("CETL"), rather than CETO, as a proxy for the share of energy consumed in the ComEd zone that is imported from other states for that LDA. The CETL reflects the *maximum* amount of out-of-zone capacity that can be relied upon to meet the reliability requirement during emergency conditions. *See* PJM Interconnection, LLC, PJM Manual 14B: PJM Region Transmission Planning Process 61 (Apr. 28, 2017), http://www.pjm.com/~/media/documents/manuals/m14b.ashx. Using the CETL rather than the CETO as a proxy for the share of out-of-state generation that consumed in Illinois recognizes that actual inter-zonal power flows will usually exceed the minimum required for reliability. The ComEd LDA's CETL was 7020 MW for the 2017-2018 RPM Base Residual Auction. *See* PJM Interconnection, LLC, 2017-2018 RPM Base Residual Auction Planning Parameters (June 2, 2014), http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx?la=en.

The statute directs the IPA to procure ZECs in an "amount *approximately* equal to 16% of the actual amount of electricity delivered by each electric utility to retail customers in the State during calendar year 2014" (emphasis added). The term "approximately" gives the IPA flexibility to procure somewhat more or somewhat less than the 16% target, and the IPA can use that flexibility to avoid the need to procure a marginal resource.

For example, if the top-ranked facilities result in a ZEC procurement equal to, say, 15% or 17% of the electricity delivered to retail customers, the IPA can select those facilities and will have achieved its statutory mandate. The IPA is *not* required to procure *exactly* 16% of electricity delivered to retail customers; it is only required to procure *approximately* that amount.

To the extent the IPA does need to choose a "marginal" facility, Exelon understands the IPA to propose that the marginal facility would be compensated only for the quantity of ZECs needed to reach the 16% target. The remaining ZECs produced by a marginal facility would be procured but treated as unpaid contractual volumes. To the extent that is the IPA's proposal, Exelon supports it but asks that the IPA issue a confirmatory clarification.

B. The ZEC Price For "Unpaid Contractual Volume" Should Be The ZEC Price Prevailing In The Year The Unpaid Contractual Volume Was Incurred.

In a year in which the ZEC Procurement Cost Cap limits the number of ZECs that may be purchased, those ZECs that are transferred to utilities but not paid for—the "unpaid contractual volume" of ZECs for that year—are eligible for payment in future years. The IPA proposes to pay for that "unpaid contractual volume" at the ZEC Price prevailing at the time the unpaid volume is purchased (i.e., at the future year's ZEC Price), but acknowledges that the "law appears to be unclear" on this point and so seeks further comments.[26]

[26] *See* Draft ZES Plan 17 n.60.

Exelon submits that the statute should be interpreted to pay for "unpaid contractual volume" at the ZEC price from the original delivery year. The statute provides that "[u]npaid contractual volume for any delivery year shall be paid in any subsequent delivery year in which such payments can be made."[27] Because the statute defines "unpaid contractual volumes" in relation to the delivery year in which those ZECs were produced ("for any delivery year"), the statute should be read to indicate that "such payments" shall be made at the price that prevailed in the delivery year the ZECs were produced.

C. Emissions Factors Should Be Based on Marginal Generation, Not Total Generation.

In determining the emissions of the units expected to replace a retiring nuclear unit, the IPA should use the statewide emission level for marginal generation (for all pollutants) rather than the statewide emission level for total generation. Currently, the Draft ZES Plan uses the average emission level within each state of *all* resources within that state, including non-polluting resources like nuclear and renewable resources.[28] As a result, in a state like Illinois, which has significant zero-carbon resources, the statewide average emission level (measured in pounds per MWh) is far lower than the per-MWh emission level of just coal and natural gas facilities in Illinois. And the average emissions level of states with many zero carbon resources is lower than the average emissions level of states with a generation mix comprised primarily of fossil fuel resources.

But as the IPA recognizes elsewhere, nuclear, renewable, and other zero-carbon facilities are at the bottom of the dispatch stack and will not be the resources relied upon to replace the output of a retiring nuclear plant. Instead, the IPA reasonably assumes, the replacement generation mix will be comprised entirely of coal- and natural gas-fired generation sources in each state (since

[27] 20 ILCS 3855/1-75(d-5)(2) (emphasis added).
[28] *See* Draft ZES Plan 33 n.103; App'x E, worksheet "2_Emissions Factors".

those are the marginal resources). Accordingly, in measuring the likely emissions impact from a nuclear retirement, the IPA should use the weighted average emissions level of *only* the coal- and natural-gas fired generation within that state—because only that generation will increase as a result of the facility's retirement, and so only its emissions are relevant. Indeed, that appears to be what the IPA intended to do: on page 34 of the Draft ZES Plan, the IPA states that it is attempting to determine the "weighted average emissions *associated with the expected replacement generation mix for that facility's state*."[29]

To obtain *that* figure, the IPA would simply sum the total emissions of all coal- and natural-gas fired generation within the state and divide that by the total MWh of coal- and natural-gas fired generation[30]—there is no need to also multiply those figures by the percentage of generation that is coal or natural gas.

Here is an example for how to implement this correction: The current formula for cell D28 in Worksheet "2_Emissions Factors" of Appendix E is "=(P28*$AB28+T28*$AC28)*2000/$AA28". If the IPA is attempting to determine the average emissions level of the coal and natural gas fired facilities in that state, the formula in that cell should be "=(P28+T28)*2000/(X28+Y28)".

The IPA also stated that it would use "statewide average" figures for CO_2 emissions, but appears to have made the same error with respect to CO_2 that it did with respect to the other pollutants. It appears that the "Statewide CO2 (lb/MWh)" figures in Column C of Worksheet "2_Emissions Factors" of Appendix E are also averages of the CO_2 emissions of *all* facilities in

[29] *See id.* at 34.

[30] These figures are currently located in rows 26 through 41 in columns H through W of worksheet "2_Emisisons Factors" of Appendix E.

the state, including zero-carbon facilities. Those figures should therefore also be corrected to be the weighted average CO_2 emissions of *only* coal- and natural gas-fired generation in each state.

D. Other Suggested Clarifications.

1) In Appendix F of the Draft ZES Plan, the IPA proposes to assess a unit's capacity factor based on historical data between 2006 and 2015.[31] The IPA requests that bidders submit "projected" generation for 2016.[32] Generation data for 2016 is, however, now available. Exelon therefore recommends that IPA request the submission of capacity factor data from 2007-2016, and that the IPA base its "Facility 10-year Average Capacity Factor" metric on that data from 2007-2016.

2) The Draft ZES Plan states that the IPA plans to use the "Average Day-Ahead" futures price at the Northern Illinois Hub to calculate the Market Price Index as part of the "ZEC Price Calculation."[33] However, the relevant provisions of 20 ILCS 3855/1-75(d-5)(1)(B)(iii)(aa) do not state whether the IPA should use "Day-Ahead" or "Real-Time" futures products to calculate the Market Price Index, and futures products in the Real-Time market are more liquid than those in the Day-Ahead market. Exelon therefore recommends that the IPA use "Real-Time" futures prices to calculate the Market Price Index.

3) Exelon seeks clarification with respect to two aspects of the data requested in Appendix F to the Draft ZES Plan. First, it is unclear whether the IPA is requesting planning year or calendar year data. Exelon therefore requests that the IPA clarify which of these sets of data it seeks in Appendix F. Second, with respect to multiple unit plants, it is unclear how IPA would like bidders to report costs that are not budgeted on a per-unit basis. Exelon suggests that bidders

[31] *See* Draft ZES Plan, App'x F, p. 3; *see also* Draft ZES Plan 44 n.130 (explaining that the 10-year average capacity factor would come from the information submitted in Appendix F).
[32] *See* Draft ZEC Plan, App'x F, p.3.
[33] *See* Draft ZES Plan 23.

should be permitted to allocate costs in equal shares across their units or in proportion to the units' capacity.

E. Spreadsheet Formula Errors.

Even if the IPA chooses not to implement Exelon's other recommendations, Exelon noticed several calculation errors in the Appendix E spreadsheet that should be corrected.

1) The "Capacity Factor" variable does not seem to be linked in any of the scoring formulas.

2) On the "3_Bid Evaluation" worksheet, each of the Scoring Metrics in columns R through V use a VLOOKUP formula that references the facility's "State," but not its "ISO." The VLOOKUP formula then refers to a table on the "2_Emissions Factors" worksheet that has two entries for Illinois. Accordingly, if a facility is in Illinois, the VLOOKUP formula will return the *first* entry for Illinois or Michigan in the referenced table on the "2_Emissions Factors" worksheet; there are, however, *two* entries for Illinois and Michigan in that referenced table because Illinois and Michigan are in both PJM and MISO. The first entry for Illinois and Michigan in the referenced table reflect the PJM-specific data for those states. Thus, an Illinois or Michigan facility located in MISO would incorrectly have values for PJM applied to it under these VLOOKUP formulas.

3) The ENE column in the wind direction table (Figure 1 in Draft Plan) is out of order, and therefore, the wind emission scoring weights for states to the East of Illinois in Appendix C and Appendix E are slightly incorrect. The ENE column should be swapped with the NNE column and the wind direction recalculated.

IV. CONCLUSION

Exelon appreciates the opportunity to comment on the Draft ZES Plan and commends the IPA on its work thus far.

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Respectfully submitted,

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Appendix A: Nuclear Unit Basis

All Operating Nuclear Units in PJM and MISO

For PJM, basis data for 2015-2016 can be found at http://www.pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx. For MISO, basis data for 2015-2016 can be found at https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx. Select “Browse All Available Reports,” and then select “Historical LMP Historical Annual Day-Ahead LMPs (zip)”.

Plant Name	Unit	State	ISO	ISO Price Node ID	Unit ISO Price Node Name	15/16 Average Day Ahead LMP	Basis to NI Hub
N Illinois Hub			***PJM***	***33092315***	***N ILLINOIS HUB***	***25.21***	
Arkansas Nuclear One	1	AR	MISO	EAI.ANO1	EAI.ANO1	19.51	-5.70
Arkansas Nuclear One	2	AR	MISO	EAI.ANO2	EAI.ANO2	19.57	-5.64
Beaver Valley	1	PA	PJM	38367975	BEAV DUQ22 KV UNIT1	26.70	1.49
Beaver Valley	2	PA	PJM	38367977	BEAV DUQ22 KV UNIT2	26.70	1.49
Braidwood Generation Station	1	IL	PJM	32417599	20 BRAID24 KV BR-1	22.95	-2.26
Braidwood Generation Station	2	IL	PJM	32417601	20 BRAID24 KV BR-2	22.90	-2.31
Byron Generating Station (IL)	1	IL	PJM	32417633	6 BYRON 25 KV BY-1	16.87	-8.34
Byron Generating Station (IL)	2	IL	PJM	32417635	6 BYRON 25 KV BY-2	16.85	-8.36
Callaway (MO)	1	MO	MISO	AMMO.CALLAWAY1	AMMO.CALLAWAY1	20.60	-4.60
Calvert Cliffs Nuclear Power Plant	1	MD	PJM	50662	CALVERTC25 KV GEN 01	33.02	7.81
Calvert Cliffs Nuclear Power Plant	2	MD	PJM	50661	CALVERTC22 KV GEN 02	33.02	7.81
Clinton Power Station (IL)	1	IL	MISO	AMIL.CLINTO51	AMIL.CLINTO51	23.31	-1.90
Davis Besse	1	OH	PJM	98370477	DAVISBES25 KV DB10	27.02	1.81
Donald C Cook	1	MI	PJM	40243801	COOK 26 KV CK1	26.17	0.96
Donald C Cook	2	MI	PJM	40243803	COOK 26 KV CK2	26.04	0.83
Dresden	2	IL	PJM	32417545	12 DRESD18 KV DR-2	24.72	-0.49
Dresden	3	IL	PJM	32417547	12 DRESD18 KV DR-3	24.62	-0.59
Duane Arnold	1	IA	MISO	ALTW.FPL_DAEC	ALTW.FPL_DAEC	19.83	-5.38
Fermi	NB 2	MI	MISO	DECO.FERMI2	DECO.FERMI2	24.45	-0.76
Grand Gulf Nuclear Station	1	MS	MISO	SME.GRANDGULF	SME.GRANDGULF	23.30	-1.91
Hope Creek	1	NJ	PJM	1097732449	HOPECREE25 KV UNIT 1	22.40	-2.81
LaSalle	1	IL	PJM	32417525	1 LASALL24 KV LA-1	23.48	-1.73
LaSalle	2	IL	PJM	32417527	1 LASALL24 KV LA-2	23.48	-1.73
Limerick	1	PA	PJM	50542	LIMERICK20 KV UNIT01	22.86	-2.35
Limerick	2	PA	PJM	50543	LIMERICK20 KV UNIT02	22.96	-2.25
Monticello (MN)	1	MN	MISO	NSP.MNTCEL1	NSP.MNTCEL1	18.89	-6.32
North Anna	1	VA	PJM	34887819	NANNA4 22 KV G1	30.63	5.42
North Anna	2	VA	PJM	34887821	NANNA4 22 KV G2	30.61	5.40
Oyster Creek (NJ)	1	NJ	PJM	50724	OYSTERCR24 KV UNIT01	23.12	-2.09
Palisades (MI)	1	MI	MISO	CONS.PALISA2A1	CONS.PALISA2A1	24.57	-0.64
Peach Bottom	2	PA	PJM	50557	PEACHBOT22 KV UNIT02	22.54	-2.67
Peach Bottom	3	PA	PJM	50558	PEACHBOT22 KV UNIT03	22.54	-2.67
Perry (OH)	1	OH	PJM	87901631	PERRY_FE22 KV PR10	27.30	2.10
Point Beach	1	WI	MISO	WEC.PTBHGB1	WEC.PTBHGB1	23.32	-1.89
Point Beach	2	WI	MISO	WEC.PTBHGB2	WEC.PTBHGB2	23.35	-1.86
Prairie Island	1	MN	MISO	NSP.PRISL1	NSP.PRISL1	19.41	-5.80
Prairie Island	2	MN	MISO	NSP.PRISL2	NSP.PRISL2	19.44	-5.77
PSEG Salem Generating Station	1	NJ	PJM	50489	SALEM 25 KV SALEM1	22.37	-2.84
PSEG Salem Generating Station	2	NJ	PJM	50490	SALEM 25 KV SALEM2	22.38	-2.83
Quad Cities (EXELON)	1	IL	PJM	32417631	4 QUAD C18 KV QC-1	16.28	-8.93
Quad Cities (EXELON)	2	IL	PJM	32417629	4 QUAD C18 KV QC-2	16.38	-8.83
River Bend	NB1	LA	MISO	EES.RVRBEND1	EES.RVRBEND1	24.61	-0.60
Surry	1	VA	PJM	34887859	SURRY4 22 KV G1	30.28	5.07
Surry	2	VA	PJM	34887861	SURRY4 22 KV G2	30.48	5.27
Susquehanna	1	PA	PJM	50654	SUSQUEHA24 KV UNIT01	23.12	-2.09
Susquehanna	2	PA	PJM	50655	SUSQUEHA24 KV UNIT02	23.29	-1.92
Three Mile Island	1	PA	PJM	50759	TMI 20 KV UNIT01	22.41	-2.80
Waterford 3	3	LA	MISO	EES.WATRFD3	EES.WATRFD3	24.02	-1.19

Appendix B: CO2 State Export Factor, Adjusted for Transmission and Distribution Losses

This data can be found in Tables 1.3.B and 5.4.B of the February 2017 "Electric Power Monthly" produced by the EIA, which can be accessed here: https://www.eia.gov/electricity/monthly/. Select "February 2017" from "Previous Issues" to obtain the year-to-date figures for 2016 through December 2016.

State	ISO	2016 Generation (GWh)	2016 Generation Adjusted for Transmission/ Distribution (GWh)	2016 Consumption (GWh)	State Export Factor*
AR	MISO	60,417	54,967	45,892	16.5%
DE	PJM	8,765	7,974	11,056	0.0%
IA	MISO	54,793	49,851	47,736	4.2%
IL	PJM	186,939	170,077	139,619	82.1%
IL	MISO	186,939	170,077	139,619	82.1%
IN	MISO	101,824	92,640	98,386	0.0%
KY	PJM	80,345	73,098	73,154	0.0%
LA	MISO	106,688	97,065	88,821	8.5%
MD	PJM	37,282	33,919	61,331	0.0%
MI	MISO	112,719	102,552	103,472	0.0%
MN	MISO	60,148	54,723	64,636	0.0%
MO	MISO	78,905	71,788	77,348	0.0%
MS	MISO	62,906	57,232	49,076	14.3%
ND	MISO	37,582	34,192	17,977	47.4%
NJ	PJM	77,620	70,619	74,769	0.0%
OH	PJM	119,356	108,590	147,637	0.0%
PA	PJM	214,811	195,435	144,582	26.0%
SD	MISO	10,363	9,428	12,090	0.0%
VA	PJM	92,439	84,101	111,910	0.0%
WI	MISO	64,797	58,952	69,466	0.0%
WV	PJM	75,626	68,805	32,070	53.4%

*This column does not reflect Exelon's recommendation, as discussed in Exelon's comments, that the IPA conservatively estimate that every state's export factor be assumed to be no less than 10.0%.